Great River Hydro
ILP Study 9 Instream Flow Consultation Meeting
Web based meeting
Tuesday, September 11, 2018, 9:30 am - 12:30 pm

Meeting Summary

Consultation on Great River Hydro's instream flow study (Study 9) continued with a web-based meeting held on September 11, 2018.

Meeting attendees identified on the telephone:

Name	Affiliation
Jeff Crocker	VT ANR
Eric Davis	VT ANR
Pete McHugh	VTFWD
Lael Will	VTFWD
Melissa Grader	FWS
Ken Sprankle	FWS
Gregg Comstock	NHDES
Mark Wamser	Gomez & Sullivan
John Hart	Gomez & Sullivan
Andrea Donlon	CRC
Kathy Urffer	CRC
Jim McClammer	CRJC
Katie Kennedy	TNC
Dan Sullivan	Lyme Properties 2 LLC
Semiu Lawal	Hatch
Steve Leach	Normandeau Associates
Edwin Nason	GRH
Shawn Keniston	GRH
Clint Birch	GRH
Rebecca Acosta	GRH
John Ragonese	GRH
Jen Griffin	GRH

Introduction

John Ragonese opened the meeting and following introductions, stepped through a power point presentation of GRH operations that focused on:

- Overview of energy markets affected by operations and instream flow,
- Operational Constraints and Impacts, and
- Project Economic concerns

The presentation was distributed during the meeting as requested by Katie Kennedy and is included with these meeting notes. Some of the presentation slides were revised for clarity after the meeting and based on discussion during the meeting. Primary discussion points are provided in this meeting summary.

Clint Birch noted that there are three energy reserve markets GRH bids into:

- 10-minute spinning reserve - the unit breaker is closed and the unit can generate to a set max within 10 minutes [post meeting note: currently, the Wilder, Bellows Falls, and Vernon projects are not bid into this market]
- 10-minute non-spinning reserve – the unit breaker is open but the unit is able to produce specified MW's within 10 minutes (post meeting note: the Wilder, Bellows Falls and Vernon projects are always bid into this market]
- 30-minute operating reserve – the amount of MW's the unit can achieve within 30 minutes.

Dan Sullivan asked if operation related to Capacity Markets was transferred into Capacity Factor. John explained it is not. Capacity factor is the ratio between actual MWh produced and potential production (MWh) of the unit or project over a one-year period.

Pay for Performance (PFP) – $2,000/MWh assessed in 5-min increments, is the current penalty for not meeting declared reserve capacity when called on by ISO-New England during a capacity scarcity condition. The penalty is increasing annually to a maximum rate of $5,450/MWh. If you underperform you lose, overperform you gain. However, the penalty is often greater than the income. We generally bid into the forward capacity market at station capacity, which is at or very near the electrical interconnection limit of the station.

Kathy Urffer asked if any of the three projects ever failed to perform when called on for capacity reserves. Edwin answered rarely, once in 2014 debris on the racks impacted operations at Wilder. John elaborated that because we have storage we can reasonably expect to meet our capacity requirement. Storage and dispatch capability allow flexibility to meet requirements.

Melissa Grader asked the difference between audits and weekly quizzes.

There two types of audits. Claimed capability audits are conducted in summer and winter on our larger units (including Wilder) and are the basis for our claimed capacity on those units insuring we have the capacity we bid into the Forward Capacity Market. For Bellows Falls and Vernon, the ISO calculates the claimed capacity based on a number of factors including amount of upstream storage, head and flows. When the ISO dispatches a unit (as opposed to normal scheduled operation) they can also "audit" and assess if we are able or not able to provide the required dispatch or if called upon provided the claimed capacity.

John explained that if the reservoir operating range is reduced, available storage is reduced, or head is reduced, GRH would not be able to produce the maximum capability we do now and thus we would lose capacity dollars.

Dan – is seasonality the limiting factor for the capacity you have to perform to?

Clint – claimed capability is based on 5-year median for each of the two seasonal periods (summer and winter). Always try to generate to the max the unit can operate. Don't audit during spill.

Melissa – how would a change in operation effect operating in these markets?

John – Limiting the reservoir range or operation, or storage capacity would affect capacity as just mentioned. Likewise, the ability to come on when called on affects our ability to participate in the reserve market. We must have the ability to respond to be in the reserve market whether or not we are dispatched. Similarly, if we are called on and cannot respond as requested, our ability to participate in this market is essentially eliminated.

There were a couple of questions about the layout of slide 12 – the order of bullets in the third column are not necessarily related to the order of bullets in the second column, and the bullets are not necessarily listed in any particular order.

Andrea Donlon asked if run-of-river projects participate in the markets.

John – CORRECTION: Some run-of-river Stations have capacity supply obligations but they are typically significantly discounted from their nameplate capability by the ISO which significantly reduces their capacity payment income.

Kathy – in another meeting I thought you said you bid zero in day-ahead market, in other words a price taker.

John – no, we don't bid zero, but we bid our minimum flow at a low price for self-schedule that takes us out of the market when running min flow (price taker). Minimum flow requirements on these projects would have to be "or inflow", couldn't be guaranteed min flow.

John – Slide 14 – ramping is huge for us, can't participate in market if unable to respond in 10 and 30 minutes.

Eric Davis – see in your table that there are impacts from up-ramping, are there any impacts from down-ramping?

Clint/Shawn Keniston – no typically not at this time, but it's something ISO is very interested in and concerned about as additional variable energy resources become part of the energy mix. The ISO is examining whether or not there should be price signals to ensure units can come off the grid as quickly as they go on.

Andrea observed that the projects don't have a lot of storage, and speculated about a 2-hr window of capacity; so, you maintain 2-hrs of full flow regardless of what the units are doing? So, ROR or reducing reservoir operation would not affect capacity.

John – the drawdown max is 0.3 ft of reservoir elevation per hour, so there are reserves. If operating flexibility is reduced, it tightens our ability to participate in the market and meet market obligations as well as potentially reduce the claimed capability.

Ken Sprankle – Slide 15 – REC value at Vernon is for units 5-8, correct?

John – yes; it is based on a calculation of the energy gain to the station from those units and a portion of the total energy produced. Although it is a significant amount presently, the price for REC's is dropping all the time; we don't anticipate REC's continuing to be available through the next 40 years.

John showed a graph of project operations and economics during a period in late September 2017 when the ISO grid was stressed. Because GRH participates in the Reserve Market, ISO did not call on us to run more than our day-ahead schedule but rather held the remaining capacity in reserve should additional fast-start resources be required during the event. ISO never called on us, but we were paid for the reserve capacity. This type of emergency event is currently more infrequent than frequent, but whether that continues is questionable given climatic conditions, fuel availability, etc. These types of events are unanticipated so difficult to predict when or how often they'll occur. It is somewhat predictable, however, that we would be held in reserve and not dispatched during these conditions.

Summary from GRH perspective:

- ISO saying it needs more flexibility – to this end we can't get rid of fast start, it's critical.
- We can't give up some of our operating constraints without flexibility.
- Struggling with the significant losses we would incur with a significant flow in the Bellows Falls bypass.

John – Considering VT's presentation at the last meeting, GRH anticipates similar information will be provided for Bellows Falls and Vernon; next steps would include looking closer at habitat specific needs from VT's presentation and what it would mean for operations.

Action Items

- GRH presentation will be finalized and distributed to the AWG.
- GRH distribute meeting notes.
- Stakeholders will review this information and call GRH with proposed next steps / agenda for next meeting.
- Next meeting scheduled for Tuesday, October 16, 2018.
- Placeholder meeting date has also been identified for November 20.

Study 9 Instream Flow, Study 24 Dwarf Wedge Mussel
Aquatic Working Group
Study Report Consultation meeting

September 11, 2018

Meeting Agenda

- Overview of Energy Markets affected by Operations and Instream Flow
- Operational Constraints and Impacts
- Project Economics concerns
  - Future of Energy Markets, Needs, Drivers and Technologies are **unknown**
  - **Value of hydro is** reflected in energy pricing – **variable, unpredictable**
  - While current markets can be described, **broader view of future** cannot rely on Renewable Portfolio Standards and Renewable Energy Credits over a **40- year license window**
  - Refer to Exhibit D

Overview of Energy Markets

- **Types of Electric Generating Resources**
  - **Baseload generating resource:** A **generating unit used to satisfy all or part of the minimum load of the system** and, as a consequence, produce electric energy continuously and at a constant rate. These units are usually economic to operate on a day-to-day basis.
  - **Intermediate-load generating resource:** A generating unit that is used during the **transition between baseload and peak-load** requirements.
  - **Peak-load generating resource:** A generating unit that is used to meet system requirements **during peak-load periods** when the demand on the system is the greatest. These **units typically operate at a relatively high cost and run when the price of electric energy is high.**
  - **Fast-start resource:** A generation unit that can start up and be at full load in less than 30 minutes, which helps with recovery from contingencies and assists in serving peak demand. These units are often held in reserve when the price of electric energy is high and capacity margin is tight.
  - **Marginal resource: The price-setting generator; the last unit committed** to meet load in economic dispatch.

Overview of Energy Markets - Generation energy markets

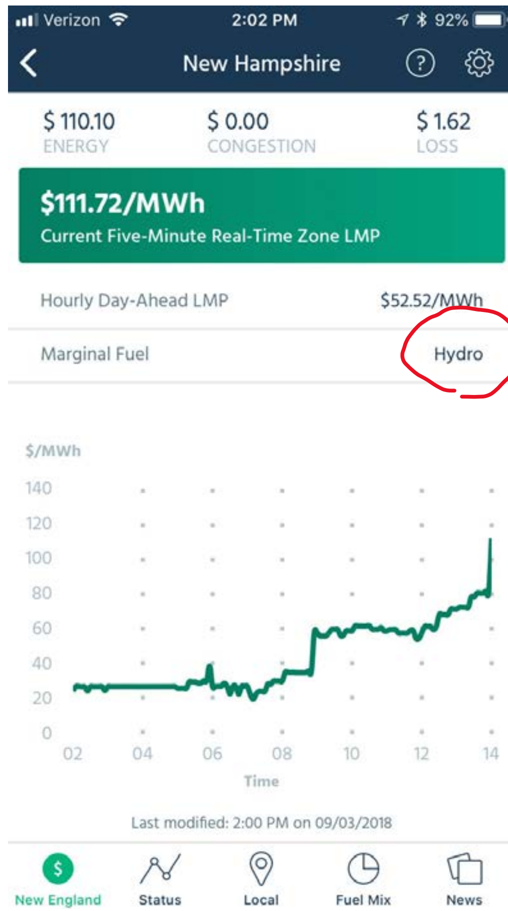
- **Day Ahead market (DA)** - a market that produces financially binding schedules for the production and consumption of electricity one day before the operating day

- **Real-time (RT) energy market** - a market that balances differences between the day-ahead scheduled amounts of electricity needed and the actual real-time load requirements

- **Locational Marginal Price (LMP):** The calculated price of electric energy at a node, load zone, reliability region, and the hub.
  - **Day Ahead prices:** Locational marginal prices reflecting the current incremental generation block bid or offer in the day ahead market.
  - **Real-time prices:** Locational marginal prices resulting from the dispatch of power within the operating day.
- **Marginal resource (fuel):** The price-setting generator; the last unit committed to meet load in economic dispatch**.**
- **Price-taker:** A market participant whose buying and selling actions do not affect the market price; a generator that has offered into the market at zero or has self-scheduled, is willing to operate at any price, and is not eligible to set clearing prices.

Overview of Energy Markets - Generation energy markets

Examples of recent high and low-load periods



Overview of Energy Markets - Ancillary Services Markets

- **Forward Capacity Market (FCM):** The locational capacity market whereby the ISO will project the needs of the power system **three years in advance** and then hold an **annual auction** to purchase power resources to satisfy the region's future needs. The aim of the FCM is to send **appropriate price signals to attract new investment and maintain existing resources** where and when they are needed, thus **ensuring the reliability of the New England electricity grid.**

  - **Capacity**: The **rated and continuous load-carrying ability**, expressed in megawatts or megavolt-amperes, of generation, transmission, or other electrical equipment.
  - **Capacity Commitment period**: The one-year period from June 1 through May 31 of the following year for which Forward Capacity Market obligations are assumed and payments are made.
  - **Capability Period**: Is one of two specific time periods within a power year. The **summer** period is June 1 through September 30; the **winter** period is October 1 through May 31.
  - **Claimed Capability:** A **generator's maximum output level as demonstrated to ISO** (twice a year for each Capability Period).

Overview of Energy Markets - Ancillary Services Markets

- **Operating Reserves -** *the "insurance policy" that allows the ISO to be able to keep electricity flowing in the event of any unexpected outages*

  The megawatt capability of a power system greater than system demand, which is required for **providing frequency regulation, correcting load forecasting errors, and handling forced outages or reserves that may be used to recover from a contingency (sudden loss of generator or transmission)** drawn from spinning and non-spinning sources of power.

  - **Forward Reserve Market (FRM):** A market used for acquiring the generating resources needed to satisfy the requirements for 10-minute non-spinning reserves and 30-minute operating reserves. It is an auction we participate in twice a year (summer and the winter) that we bid into to secure an obligation for the following capacity period to provide reserves.
  - **Real-time Reserve Market:** An ISO market where resources capable of providing 10-minute and 30-minute reserves are designated in real time, for which they are paid the reserve market clearing price.

GREAT RIVER HYDRO

Overview of Energy Markets - Ancillary Services Markets

Three types of Reserves in the Real Time Reserve market:

- **Ten-Minute Spinning Reserve (TMSR):** The **reserve capability** that an online, synchronized generator can fully convert into electric energy **within 10 minutes** after receiving a request (DDP or Desired Dispatch Point) from ISO New England to do so.

- **Ten-Minute Non spinning Reserve (TMNSR): Off-line generation that can, within 10 minutes, be electrically synchronized** to the system and increase output to respond to a contingency and serve demand after receiving a DDP from ISO New England to do so. . Wilder Example – Wilder is producing 18 mw's and its max is 41, ISO would have 23 mw's into the TMNSR market.

- **Thirty-Minute Operating Reserve TMOR):** This is the amount of MW's that we can achieve on an asset in 30 minutes which is always the same or higher than what we can do in 10.

Overview of Energy Markets - Ancillary Services Markets

- **Pay-for-performance (PFP)**

  A design feature of the Forward Capacity Market which provides incentives for resource owners to make investments to ensure their resource's perform during capacity scarcity conditions (CSCs).

  A CSC is when there is a deficiency in one or more of the three reserve requirements:

  - The ISO must maintain a sufficient amount of reserves to be able to **recover from the loss of the largest single system contingency within 10 minutes**.
  - Additional reserves must be available **within 30 minutes to meet one-half of the second-largest system contingency**.
  - The ISO also identifies **local resources** to meet the second-contingency requirements **in import-constrained areas**.

  A CSC can occur in one or more five-minute pricing intervals.

Overview of Energy Markets - Ancillary Services Markets

- **Pay-for-performance (PFP)**

  Penalizes or rewards resources based on their performance below or above their [obligated] share of the system's requirements. Eliminated the many exceptions allowed for underperformance under the previous FCM rules.

  Failure-to-Activate Flag: A flag placed on a forward-reserve resource when the **resource fails to respond** when asked to **activate its claimed 10-minute non-spinning reserve or 30-minute operating reserve**. A Failure-to-Activate flag results in **a <u>financial penalty</u>**.

  Failure-to-Reserve Flag: A flag placed on a market participant's delivered forward-reserve megawatts associated with a reserve zone when these megawatts are less than the participant's associated forward-reserve obligation. **A Failure-to-Reserve flag results in a forfeiture of payment for any forward-reserve megawatts not delivered <u>plus a financial penalty</u>.**

Overview of Energy Markets – Emergency and Scarcity Events

- **Emergency:**
  - Abnormal condition of an electric system requiring manual or automatic action to maintain system frequency or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of the system or the safety of people or property.
  - Could also be a fuel shortage requiring departure from normal operating procedures to minimize the use of such scarce fuel or any condition that requires the implementation of emergency procedures by ISO.

- **Shortage event:** A designated period (hours) of system stress during which capacity resources are most needed on the basis of system conditions.
- **Reserve-Shortage Pricing Event:**
  - When the control area is **experiencing a deficiency in total 10-minute operating reserves** or the ISO is taking actions to maintain 10-minute operating reserves.
  - The ISO will also declare this condition when the control area is experiencing **a deficiency in total operating reserves that has lasted for at least four hours** and the ISO has begun taking actions to maintain or restore operating reserves.

Overview of Energy Markets – Power System Status Descriptions

- **Normal -** Conditions are considered normal when electricity supply is sufficient to meet expected demand plus required operating reserves**.**
- **Master/Local Control Center Procedure No. 2 (M/LCC 2) alert** is issued either for the entire region or for a local area when abnormal conditions on the region's power system exist or are anticipated.
- **OP 4 (ISO Operating Procedure No. 4) Action during a Capacity Deficiency** - when available resources are insufficient to meet anticipated electricity demand plus required operating reserves. **The procedure includes 11 actions that the operators can take to either increase the available supply of electricity for the region or reduce the actual real-time demand for electricity.** These actions can be implemented in any order depending on the circumstances of the capacity deficiency. In addition, some of the actions can be implemented in advance of an anticipated capacity deficiency situation.
- **Minimum Generation Emergency (CROP.25005)**
- **Cold Weather Watch, Cold Weather Warning, or Cold Weather Event**
- **Energy Emergency** in the Seven-Day Capacity Forecast. The Energy Emergency is declared when the ISO forecasts a shortage of fuel for generators resulting in a potential loss of operable generating capacity needed to meet requirements for system demand for electricity and ten-minute operating reserves..

Operational Constraint Scenario – Impacts

CONSTRAINT	IMPACT	FLEXIBILITY to Address Impacts
Reservoir Stabilization		
Reduction in Impoundment Operating Range Reduce Drawdown Rate	• Loss of Capacity and capacity payments; Increased risk to not meeting capacity supply obligation • Reduction or loss of Forward and Real-time Reserves • Pay-for-Performance penalty risk • Loss of generation due to lack of storage • Shift from peak to off-peak generation • Reduction in energy income	• Need to exercise reservoir when called upon by ISO. • Need to exercise reservoir to conduct winter and summer audits
Stabilized Reservoir; inflow equal outflow	• Loss of all rated Capacity and capacity payments; • Loss of Forward and Real-time reserves • Pay-for-Performance penalty • Loss of generation due to lack of storage • Shift from peak to off-peak generation • Reduction in energy income	• Need to exercise reservoir when called upon by ISO. • Need to exercise reservoir to conduct winter and summer audits
Reduction in Reservoir Profile Operation range	• Potentially greater energy generation in some instances when flows are just above the threshold but not likely to cause spill • Potentially loss of energy generation due to higher likelihood of spill	• Need to operate for flood control and abatement

Operational Constraint Scenario – Impacts

CONSTRAINT	IMPACT	FLEXIBILITY to Address Impacts
Minimum Flow		
Below the Station	• Shift from peak to off-peak generation • Reduction in energy income – price-taker	• Must be or inflow – upstream gage plus calculated inflow below gage & above dam
Minimum flow Into Bellows Falls bypass	• Significant Generation loss • Significant reduction in energy income • Potential loss of capacity due to lack of water and/or head losses • Loss of reserve capability and revenue due to lack of water/or head losses • Greater exercise of storage (reservoir range) to meet capacity obligation • Pay-for-Performance penalty risk	• Must be proportionally reduced if total inflow is less than minimum flow requirement.

Operational Constraint Scenario – Impacts

CONSTRAINT	IMPACT	FLEXIBILITY to Address Impacts
Discharge Constraints		
Ramping Rates Increasing and Decreasing Generation	• Loss of Capacity and capacity payments; Enhanced risk to not meeting capacity supply obligation • Loss of reserve capability and revenue • Pay-for-Performance penalty • Reduction in energy income	• Need to ignore ramping requirement when called to dispatch by ISO – 10-minute spinning and 30-min non-spinning reserves. • Need to ignore ramping requirement when called to dispatch by ISO in order to meet forward capacity obligation.
Maximum station discharge reduced	• Loss of Capacity and capacity payments; Enhanced risk to not meeting capacity supply obligation • Loss of reserve capability and revenue • Pay-for-Performance penalty • Reduction in energy income	• Need to ignore maximum discharge requirement when called to dispatch by ISO – 10-minute spinning and 30-min non-spinning reserves. • Need to ignore maximum discharge requirement when called to dispatch by ISO in order to meet forward capacity obligation. • Need to maximize station discharge if headed toward spill
Scheduled generation	• Loss of Capacity and capacity payments; Enhanced risk to not meeting capacity supply obligation • Loss of reserve capability and revenue • Pay-for-Performance penalty • Potential loss of energy generation due to lack of reservoir optimization • Reduction in energy income – price taker	• Need to ignore generation schedule requirement when called to dispatch by ISO – 10-minute spinning and 30-min non-spinning reserves. • Need to ignore generation schedule requirement when called to dispatch by ISO in order to meet forward capacity obligation.

Economics

Exhibit D License Applications - Annual Value of Project Power (2016 $'s and 10-yr Ave generation)

REVENUE SOURCE VALUE	WILDER		BELLOWS FALLS		VERNON	
On-peak Energy	$ 2,827,376	36%	$ 3,847,877	36%	$ 2,680,181	29%
Off-peak Energy	$ 2,176,829	27%	$ 3,696,990	34%	$ 2,264,803	25%
Capacity	$ 2,512,818	32%	$ 2,963,367	27%	$ 1,953,600	21%
Real-time reserves	$ 371,372	5%	$ 259,358	2%	$ 259,478	3%
Volt-ampere-reactive support	$ 32,003	0%	$ 23,455	0%	$ 15,029	0%
RECs	$ -	0%	$ -	0%	$ 2,020,000	22%
Total value	**$ 7,920,398**	**100%**	**$ 10,791,047**	**100%**	**$ 9,193,091**	**100%**
Annual costs (30 yr yr analysis) Incl. cost of capital, taxes, depreciation/amortization, O&M)	$ 6,219,165		$ 10,444,894		$ 7,327,917	

Economics

- Current Value mix in % of revenue for LC Projects (YT 7/18) :
  - Energy 64-66%
  - Forward Capacity 27% - 32%
  - Other Ancillary (includes reserves) 1-2%
  - RECs (Vernon 5-8) 7%

- Forward Capacity Supply obligation
  - 100% station capacity through May 31, 2022
  - As of 2/19, through May 31, 2023

Economics

- Having the flexibility in our operations to participate in Capacity and Reserves Markets is ESSENTIAL

- Exercising that flexibility is distinct from having the flexibility.

- LC Hydro as a FAST-START resource is critical to the ISO and therefore more often NO RUN but held in reserve

- September 24-28-2017 is an example